COMMERCE DEPARTMENT

September 13, 2023

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E017/RP-21-339

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> In the Matter of Otter Tail Power Company's Application for Supplemental Resource Plan Approval 2023–2037.

The Supplement was filed by Otter Tail's Nathan Jensen, Manager, Resource Planning on March 31, 2023.

The Department recommends **the Minnesota Public Utilities Commission and Otter Tail Power Company take certain actions** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ LOUISE MILTICH
Assistant Commissioner of Regulatory Analysis

/s/ STEVE RAKOW
Analyst Coordinator

LM/SR/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E017/RP-21-339

I. INTRODUCTION

A. RESOURCE PLAN PETITION

On September 1, 2021, Otter Tail Power Company (OTP or the Company) filed the Company's *2022–2036 Integrated Resource Plan* (Petition). The Petition was filed in compliance with the Minnesota Public Utilities Commission's (Commission) April 26, 2017 *Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan* (2017 IRP Order) in Docket No. E017/RP-16-386.[1] The Petition proposed a five-year action plan, including the installation of dual fuel capability at OTP's Astoria Station (Astoria).

On October 14, 2022, OTP filed a letter requesting the Commission bifurcate the procedural schedule to allow the Company to revise the integrated resource plan (IRP) modeling and provide any necessary updates in March 2023 and not apply the proposed amended procedural schedule to that part of the Petition concerning installing dual fuel capability at Astoria.

On November 1, 2022, the Commission issued its *Notice of Extended Comment Period* adopting OTP's proposal to bifurcate the Petition.

On March 31, 2023, the Company filed its *Application for Supplemental Resource Plan Approval 2023–2037* (Supplement). The Supplement requests authority to carry out the following five-year action plan:

- add onsite liquified natural gas (LNG) fuel storage at Astoria in 2026;
- add approximately 200 MW of solar generation in the 2027-2028 timeframe;
- take the initial steps necessary to add approximately 200 MW of wind generation in the 2029 timeframe; and
- withdraw from OTP's 35 percent ownership interest in Coyote Station (Coyote) in the event OTP is required to make a major, non-routine capital investment in Coyote.

The Supplement summarizes and explains the changes to the action plan as follows:

> Compared to our Initial Preferred Plan, our Supplemental Preferred Plan proposes to add more renewable generation resources to our portfolio. The most significant change between our Initial Preferred Plan and our Supplemental Preferred Plan concerns Coyote Station. As a winter peaking

[1] The original due date was later extended by Commission orders issued December 13, 2018 and December 30, 2019 in Docket No. E017/RP-16-386.

> utility we are particularly concerned about MISO's [Midcontinent Independent System Operator, Inc.] new seasonal reserve margin requirements, open questions concerning MISO accreditation methodologies, and projected capacity deficits within MISO - especially when we consider changes to our load forecasts. These and other factors discussed herein raise significant concerns about our future capacity position and the degree to which MISO capacity and energy markets will be available to support our fundamental obligation to ensure system resource adequacy at a reasonable cost. In this unsettled environment, the value of existing dispatchable capacity offered by Coyote Station augers against a premature and irretrievable withdrawal from the plant that may unnecessarily expose our customers to risk.

B. ASTORIA ON-SITE FUEL STORAGE

On November 4, 2022, the Company's *Supplemental Comments Summarizing Otter Tail's Request for Authority to Commence Development of On-Site Fuel Storage at Astoria Station* (Revised Proposal) revised OTP's proposal to install dual fuel capability at Astoria.

On December 30, 2022, comments on OTP's Revised Proposal were filed by:

- Minnesota Department of Commerce, Division of Energy Resources (Department);
- Operating Engineers Local 49 and North Central States Regional Council of Carpenters;
- LIUNA Minnesota and North Dakota;
- Office of the Attorney General—Residential Utilities Division (OAG).

On February 1, 2023, reply comments were filed by:

- Clean Energy Organizations (CEO);[2]
- OAG; and
- OTP.

On February 16, 2023, supplemental comments were filed by the Company.

On May 16, 2023, the Commission issued its *Order Reintegrating Astoria Station Dual Fuel Proposal with Resource Plan* which moved consideration of OTP's Astoria Station dual fuel proposal back into the Company's IRP.

On June 23, 2023, OTP filed *Supplemental Comments Concerning Astoria Station On-Site LNG Fuel Storage*. This filing provided additional information on the Astoria Station dual fuel proposal.

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[2] This group consists of Fresh Energy, Clean Grid Alliance, Minnesota Center for Environmental Advocacy, and Sierra Club.

C. BACKGROUND ON OTP

According to the Petition's Appendix B OTP provides electricity and energy services for approximately 125,000 residential, commercial, and industrial customers in Minnesota, North Dakota, and South Dakota. According to the Supplement, in all three states OTP serves very small rural towns—the average population of the communities in OTP's three-state region is approximately 400 people. In 2020 OTP's 4.8 million MWh of energy sales were distributed as follows:

- Industrial—51.3%;
- Non-farm Residential—26.4%;
- Commercial—18.3%;
- Farm—2.3%;
- Other—1.2%; and
- Street and Highway Lighting—0.4%.[3]

Note that EIA's early release of Form 861 shows that OTP's energy sales were 5.6 million MWh in 2022;[4] an increase of 16.5 percent over the 4.8 million MWh two years prior.

This Data on the Company's existing resources is summarized in Table 1.

Table 1: Existing Capacity[5]

Fuel Type	ICAP (MW)	SAC (MW) Summer	Fall	Winter	Spring
Coal	407	414	403	406	411
Natural Gas	292	283	296	301	322
Load Control	Varies	126	139	249	153
Wind	391	81	102	202	107
Fuel Oil	60	60	74	76	73
Hydro	11	11	11	11	11
Diesel	4	4	4	4	4
Solar	49	Deferred	Deferred	3	25
Small Wind/Solar	14	N/A	N/A	N/A	N/A
TOTAL	1,229	980	1,028	1,252	1,106

Table 2 below uses EnCompass modeling results to compare OTP's coincident peak demand[6] to existing resources and shows the resulting reserve margin. Table 2 shows that the winter and summer seasons clearly will be the driving force in OTP's resource planning, at least for capacity purposes. The spring and fall seasons are unlikely to be of importance. In addition, Table 2 shows that, with no further actions, OTP will first encounter very small capacity surpluses or deficits in the early 2030s. Therefore, near term actions would be taken to address energy issues rather than capacity issues.

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[3] Data taken from the Petition's Appendix B, Electric Utility Report, 7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS.
[4] Accessed August 25, 2023 and available at: https://www.eia.gov/electricity/data/eia861/
[5] This data summarizes detailed information shown in the Supplement's Appendix C, Tables 1-1 and 1-2.
[6] In OTP's modeling coincident peak demand also accounts for the seasonal planning reserve margin.

Table 2: Existing Supply and Demand[7]

Year	Coincident Peak (MW)				Existing Firm Capacity (MW)				Existing Margin			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
2023	1,013	699	732	660	1,071	929	857	913	5.7%	32.9%	17.0%	38.3%
2024	1,014	700	735	662	1,071	929	857	913	5.5%	32.7%	16.5%	37.8%
2025	1,096	762	804	723	1,125	960	878	942	2.6%	26.1%	9.1%	30.4%
2026	1,098	763	807	725	1,127	961	879	943	2.6%	26.1%	8.8%	30.1%
2027	1,100	764	811	727	1,128	963	880	944	2.6%	26.1%	8.6%	29.9%
2028	1,100	764	812	730	1,129	964	881	946	2.6%	26.2%	8.4%	29.5%
2029	1,103	766	816	733	1,122	961	878	942	1.7%	25.5%	7.6%	28.5%
2030	1,106	767	820	736	1,123	962	879	943	1.6%	25.3%	7.2%	28.1%
2031	1,108	769	824	739	1,110	923	869	933	0.1%	20.1%	5.5%	26.2%
2032	1,105	767	822	737	1,113	925	870	934	0.7%	20.6%	5.9%	26.8%
2033	1,102	765	819	735	1,108	924	810	874	0.5%	20.8%	-1.1%	18.9%
2034	1,109	770	825	740	1,053	867	811	875	-5.1%	12.7%	-1.7%	18.2%
2035	1,114	773	829	743	1,056	869	813	876	-5.2%	12.3%	-2.0%	17.8%
2036	1,119	777	834	747	1,060	871	814	878	-5.3%	12.1%	-2.4%	17.6%
2037	1,123	780	837	750	1,060	871	814	878	-5.6%	11.7%	-2.8%	17.1%

[7] Data taken from Department EnCompass matching results for OTP's 2040 Coyote Retirement base case. Note that "Existing Margin" is calculated as the percent difference between existing firm capacity and coincident peak.

II. DEPARTMENT ANALYSIS

A. APPLICABLE STATUTES AND RULES

The Commission's IRP process is governed by Minnesota Statutes § 216B.2422 and Minnesota Rules 7843. As indicated in the Petition's Appendix A, there are numerous other statutes, rules, and Commission orders which impact the decision in this proceeding. Regarding the Commission's decision, Minnesota Rules 7843.0500 subp. 3 states:

> In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
>
> A. maintain or improve the adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

In summary, the Commission evaluates a proposed IRP based upon its ability to create a reliable, low cost, low environmental and socioeconomic impact system that manages risk. In weighing these factors, the Commission must consider other factors such as the statutory preference for renewable energy facilities.

B. FORECAST

The Supplement explained the changes to EnCompass' forecast inputs as follows:

> As detailed in Otter Tail's August 2, 2021, Prefiling, the Initial Filing sales and demand forecasts were completed in early 2021 using actual sales data through December 2020. Since then, we have added new large load customers with the addition of other large load customers expected within the next 24 months. These new large loads are included in the sales and demand forecast inputs to our EnCompass expansion capacity modeling and were considered in developing the Supplemental Preferred Plan. From an energy perspective, the impact of new customers on the sales forecast is a 16 percent to 18 percent increase in energy requirements over the planning period as compared to the Initial Filing.

The Department compared EnCompass' forecast outputs from files provided by OTP for the Petition to outputs from files for the Supplement. The forecasted change in MW and MWh, along with a calculated load factor for the change, is summarized in Table 3 below. The data in Table 3 is consistent with the large loads described by OTP.

Table 3: Forecast Change

Years	Calculation	Monthly Peak (MW)	Monthly Energy (GWh)	Load Factor
2023-'24	**Monthly Minimum Increase**	118.0	60.1	70.7%
	Monthly Average Increase	124.9	74.5	82.8%
	Monthly Maximum Increase	135.8	92.0	94.1%
2025-'50	**Monthly Minimum Increase**	178.6	97.6	75.9%
	Monthly Average Increase	187.3	112.4	83.4%
	Monthly Maximum Increase	201.5	135.0	93.1%

Note that the Company's reply to OAG Information Request (IR) No. 15 provides further details on the spot load adjustments.

1. Introduction

Both the Petition and Supplement were prepared using the Company's *Advanced Forecast Report* for 2021 (AFR2021)—for details see the Petition's Appendix B. OTP's AFR2021 was filed on June 29, 2021 in Docket No. E999/PR-21-11. According to the Petition:

> The energy requirements forecast represents an approximately 0.46 percent average annual growth rate, prior to new demand side management (DSM) programs … Peak demands are anticipated to average an annual growth rate of 0.57 percent in the summer, prior to new DSM programs …
>
> When comparing the load forecast from our 2016 IRP to the updated forecast used in this IRP there is a noticeable reduction in the current forecast. This reduction is a result of energy efficiency programs. Otter Tail has seen significant demand and energy savings, in excess of three percent in some years. Another factor contributing to our forecast reductions is a decrease to firm demand requirements from our large industrial customers.

The Department had two goals in its review of the AFR2021 forecast in this IRP. First, to be done quickly as the forecast is an input to the remaining analysis. Second, to establish an acceptable base forecast and an acceptable forecast range for long term planning purposes. Given these limits, the forecast review did not address some details that would normally be part of forecast analysis. This means that the Department neither reviewed the technical details of OTP's forecasts nor tested all the Company's previous or current statistical models. Instead, as with other recent IRPs the Department examined the potential for bias in OTP's forecasting over the past two decades.[8]

As described below, the review indicates that any bias present in the Company's demand forecasts would be far too small to impact the IRP—the average error in the first ten forecast years is between ±2 percent in all but the ninth forecast year. The Company's energy forecasts show a persistent bias; the forecast is too high by between two and five percent in all but the tenth forecast year. Given the new large, energy intensive loads added by the Company since the forecast (see Table 3 above), the Department determined that no adjustment to OTP's base energy forecast was warranted.

2. Data Analyzed

The data on past actual demand and energy requirements for OTP's system during 2006 through 2020 was taken from the Company's response to Department IR Nos. 2 and 4. The data on the Company's forecasts of annual peak demand and energy requirements issued from 2005 through 2019 were taken from the Company's response to Department IR No. 3.

Using OTP's responses, the Department compared actual energy sales (Department IR No. 4) and peak demand (Department IR No. 2) for the years 2006 to 2020 to OTP's demand and energy forecasts (Department IR No. 3) prepared from 2005 through 2019.

3. Demand Forecast Process

The Department's first step in analyzing OTP's demand forecast process was calculating the MW difference between forecasted demand and actual peak demand. The Department's second step was to determine the size of the average error (in MW) resulting from the demand forecast process. The error was calculated for the first forecast year, the second forecast year, and so on. The average of the absolute value of the errors was consistently between 35 MW and 50 MW for all forecast years. This is approximately the size of the wind (50 MW) and solar (25 MW) expansion units used by OTP in EnCompass. Considering the uncertainty inherent in IRP modeling, the size of the errors is not of concern.

The Department's third step was to calculate the percent error in order to help determine the appropriate forecast adjustment, if any, and the forecast bands. The result of this calculation is shown below in Table 4. For easy identification, the Department shaded the cells in Table 4 that are negative. When considering all forecasts, about 42 percent of the data points are positive and 57 percent are negative. Based upon this data the Department concludes that there is no clear evidence of a systematic bias in OTP's demand forecast process.

[8] For example, See the Department's comments in Docket Nos. E002/RP-19-368 and E015/RP-21-33.

Table 4: OTP's Demand Forecast Error (percent)

Year	2005 Fcast	2006 Fcast	2007 Fcast	2008 Fcast	2009 Fcast	2010 Fcast	2011 Fcast	2012 Fcast	2013 Fcast	2014 Fcast	2015 Fcast	2016 Fcast	2017 Fcast	2018 Fcast	2019 Fcast
2006	-6.5%														
2007	-5.2%	5.7%													
2008	-11.4%	-1.6%	-6.5%												
2009	-13.7%	-4.6%	-9.3%	-4.7%											
2010	-12.4%	-3.3%	-8.5%	-2.0%	-8.9%										
2011	-7.2%	2.1%	-3.2%	5.4%	-0.8%	4.9%									
2012	-3.4%	5.6%	0.4%	7.2%	0.0%	8.8%	1.4%								
2013	-5.6%	2.7%	-2.6%	3.0%	-3.6%	6.4%	-1.6%	-1.6%							
2014	-7.6%	-0.1%	-4.9%	-1.0%	-6.5%	5.0%	-4.1%	-4.1%	-4.1%						
2015	-5.5%	1.7%	-2.7%	-2.5%	-6.5%	8.0%	-4.2%	-4.2%	-4.2%	-4.1%					
2016	-3.6%	-1.4%	-1.4%	-2.1%	-4.9%	10.9%	-2.2%	-2.2%	-2.2%	-4.6%	-4.6%				
2017	-3.6%	-1.4%	-1.4%	-2.3%	-3.5%	12.8%	-0.3%	-0.3%	-0.3%	-5.2%	-5.2%	1.5%			
2018	-1.6%	0.7%	0.7%	-0.7%	0.3%	15.3%	1.6%	1.6%	1.6%	-2.0%	-2.0%	3.7%	5.6%		
2019	-1.3%	1.0%	1.0%		0.4%	15.6%	1.6%	1.6%	1.6%	-2.3%	-2.3%	4.2%	4.7%	3.9%	
2020		10.3%	10.3%				12.7%	12.7%	12.7%	8.5%	8.5%	14.5%	14.3%	15.4%	13.5%

The percent error was then calculated for the first forecast year, the second forecast year, and so on. The result was that, one year out, OTP's average error equals (0.3) percent. Three years out OTP's average error is about (0.9) percent. By five years out OTP's average error is 0.0 percent. By seven years out OTP's average error is 1.8 percent. This data indicates that the early years of OTP's demand forecast tend to be too low by a small amount and the later years of OTP's demand forecast tend to be too high, again by a small amount. Overall, the Department concludes that the demand forecast errors do not exhibit a clear bias and, in any case, the demand forecast errors are too small to be meaningful.

4. Energy Forecast Process

The Department repeated the analysis of OTP's demand forecast process for OTP's energy forecast process. Overall, the Department found that the Company's energy forecasting exhibited more bias than the demand forecasts. Note that not all energy forecast vintages forecasted the same years as the equivalent demand forecast vintages and, as a result, the table below is slightly different than the equivalent demand forecast table above. For example, the 2008 demand forecast covered the years 2009 to 2012 but the 2008 energy forecast covered the years 2009 to 2018.

The Department began the analysis of OTP's past energy forecasts by calculating the difference between the forecasted and actual energy in GWh. The GWh error was then converted into a percent error. The results of this calculation are shown below in Table 5. In Table 5 a positive number indicates the energy forecast turned out to be too high and a negative number indicates that the energy forecast turned out to be too low. For easy identification, the Department shaded cells in Table 5 that are negative.

Table 5: OTP's Energy Forecast Error (percent)

Year	2005 Fcast	2006 Fcast	2007 Fcast	2008 Fcast	2009 Fcast	2010 Fcast	2011 Fcast	2012 Fcast	2013 Fcast	2014 Fcast	2015 Fcast	2016 Fcast	2017 Fcast	2018 Fcast	2019 Fcast
2006	-0.5%														
2007	-1.1%	2.9%													
2008	-1.9%	2.0%	-0.1%												
2009	-1.3%	2.7%	0.5%	5.5%											
2010	-1.4%	2.5%	0.4%	5.5%	12.4%										
2011	-0.2%	3.8%	1.6%	6.7%	15.4%	1.4%									
2012	-9.9%	-6.2%	-8.3%	-4.0%	10.5%	-9.1%	-5.4%								
2013	-1.3%	2.6%	0.4%		23.0%	0.5%	4.7%	8.0%							
2014	-4.4%	-0.6%	-2.8%			-3.0%	2.7%	3.6%	3.6%						
2015	-0.6%	3.4%	1.1%				8.0%	10.2%	10.2%	1.9%					
2016	-3.6%		-2.0%				5.3%	5.7%	5.7%	0.4%	-3.2%				
2017	-3.2%		-1.6%				7.2%	8.0%	8.0%	-0.7%	-0.6%	3.1%			
2018	-3.2%		-1.7%				9.7%	10.7%	10.7%	-1.6%	-2.3%	3.0%	-1.9%		
2019	-1.0%		0.6%				11.0%	12.7%	12.7%	2.3%	-0.9%	2.4%	1.5%	0.2%	
2020			5.4%				15.1%	17.5%	17.5%	6.2%	5.2%	5.4%	5.7%	6.7%	3.9%

When considering all of OTP's energy forecasts, about 65 percent of the data points are positive and only 35 percent are negative. Based upon this data, the Department concluded that there is some evidence of a systematic bias in OTP's energy forecast process. The Company's energy forecast is frequently too high.

While not shown, the size of the energy forecast error may also be of interest. The error was calculated for the first forecast year, the second forecast year, and so on. The result of the calculation was that two years out OTP's average energy forecast error is about 136 GWh. Four years out OTP's average energy forecast error is about 166 GWh. By six years out OTP's average energy forecast error is about 217 GWh and at eight years out OTP's average energy forecast error is 270 GWh. For context, in OTP's EnCompass modeling 270 GWh is equivalent to the energy output from about 60 MW of new wind or 125 MW of new solar.

Next the Department calculated the percent error for the first forecast year, the second forecast year, and so on. The result was that two years out OTP's average energy forecast error equals 3.1 percent. Four years out OTP's average energy forecast error is about 3.6 percent. By six years out OTP's average error is 4.4 percent. Finally, at eight years out OTP's average error is 5.6 percent.

In summary, the energy forecast tends to be too high by between 3 percent and 6 percent. As mentioned above, due to the addition of large, energy intensive loads the Department ultimately determined that no forecast adjustment was warranted.

5. Degree Days Treatment

The April 2, 2021 *Direct Testimony and Attachments of Sachin Shah* in Docket No. E017/GR-20-719 at pages 28 to 32 discussed OTP's use of 55° Fahrenheit (F) as a base in calculating the actual and normal Heating Degree Days (HDDs) that OTP used in its sales forecast models rather than a 65°F base. In response to the Mr. Shah's concerns, the Commission's February 1, 2022 *Findings of Fact, Conclusions, and Order* in Docket No. E017/GR-20-719 stated:

> The Commission respectfully disagrees with the ALJ that modifying the HDD as proposed by Otter Tail is supported by the record. The Commission concurs with the Department that the Company has not established that reducing the HDD by 10 degrees better captures the point at which heating load begins to increase.

To follow upon the HDD degree base issue, Department IR No. 6 requested OTP to revise the system-wide energy and demand forecasts so that all variables use a 65°F degree-day base rather than a 55°F degree-day base, and separately provide the resulting MW and MWh forecasts.

The results of comparing the forecast using a 65°F degree-day base rather than a 55°F degree-day base is that annual peak demand increased a small amount. The result for the annual energy forecast is that the annual energy requirement decreased by small amount. The small changes were not of a size that they could impact the IRP in a meaningful way. Thus, the Department did not pursue the issue further.

6. Pipeline Forecast

Regarding OTP's forecast of pipeline requirements, the 2017 IRP Order stated:

> The Clean Energy Organizations stated that load forecasting based on pipeline sales should be clearer. The Commission agrees and will therefore require Otter Tail to include a transparent methodology to reflect forecasted load associated with pipelines or pipeline replacements.

In response OTP's August 2, 2021 *Energy and Demand Forecast Models Information Filing* in in this proceeding stated:

> Due to difficulty using economic models to forecast Pipeline customer load, Otter Tail forecasts pipelines using input from the customers' own projections, among other inputs. This load is significantly impacted by world and national economic trends and federal and state energy and environmental policy.
>
> One other large commercial customer is forecasted manually, with input from the customer themselves and Otter Tail large commercial specialists.

The November 2, 2020 *Direct Testimony of Debra K. Opatz* in Docket No. E017/GR-20-719, OTP's most recent rate case, had a similar explanation of pipeline forecasting:

> Pipeline sales are very difficult to forecast using statistical models and therefore are forecasted manually by OTP employees that work directly with the Pipeline customers.
> …
> Pipeline sales are significantly impacted by world and national economic trends and federal and state energy and environmental policy. Further, the petroleum industry is in a state of constant flux. Lastly, OTP serves very few customers in this class, so regular predictable patterns often do not emerge. These factors are difficult to capture in statistical models.
> …
> OTP works very closely with the pipeline companies to acquire their updated demand (kW) and energy (kWh) projections. The 2021 Test Year Pipeline sales forecast incorporates the customers' own projections of 2021 usage, historic sales information, comparisons of how the customers' projections have compared to actual results and recent sales trends.

Overall, the Department concludes OTP has consistently and clearly described the Company's forecasting method for pipeline sales in recent filings. Given the unique nature of pipeline customers there are limits on how transparent the pipeline forecast can be.

7. *Conclusion*

The main conclusion from the analysis is that OTP's demand and energy forecast processes have very little systematic bias. The demand forecast error is consistently small and does not show enough tendency towards being too high or too low to determine systematic bias is present. OTP's energy forecast errors also appear to be relatively small. However, the energy forecast error is too high much more often than too low and thus an adjustment may have been warranted. However, the Company's recent addition of several large loads indicates that no adjustment is warranted until the energy and demand requirements of the new loads are better understood.

C. MISO'S DOWNWARD SLOPED DEMAND CURVE

In February 2018 the Federal Energy Regulatory Commission (FERC) issued an order rejecting MISO's proposed downward-sloped demand curve (DSDC). The February 2018 order was later described by FERC[9] as follows:

> In the February 2018 Order, the Commission found that, given the extremely high proportion of vertically integrated utilities and the active role that states have played in ensuring resource adequacy, the vertical demand curve is just and reasonable for use in MISO's resource adequacy construct.[232] The Commission stated that recognizing the diminishing marginal benefits of excess capacity was not essential to ensuring that LSEs in MISO acquired sufficient capacity to maintain the one day in 10 year reliability standard. The Commission explained that accepting both vertical and sloped demand curves in different markets is consistent with precedent that filings made under section 205 "need not be the only reasonable methodology, or even the most accurate," so long as it is just and reasonable.[233]
>
> [231] February 2018 Order, 162 FERC ¶ 61,176 at P 60.
> [232] *Id*. PP 67-69
> [233] *Id*. P 68 (quoting Oxy USA, Inc. v. FERC, 64 F.3d at 692)

For most of 2023, MISO has been discussing a proposal to re-file a DSDC proposal at FERC. Briefly, MISO's new DSDC proposal attempts to calculate the money that is missing from MISO's markets but necessary for an independent power producer (IPP) to profit from construction of a new natural gas fired combustion turbine (CT). Essentially, under a DSDC, MISO:

1. calculates the cost of building a new CT—referred to as the Cost of New Entry (CONE);
2. subtracts from CONE the expected net revenues (income minus expenses) from the energy and ancillary services markets—the resulting figure is referred to as Net CONE; and

[9] Quotation taken from point 112 of FERC's *Order Denying Rehearing*, dated March 20, 2020 issued in FERC Docket No. ER18-462-001.

3. creates a demand curve for the annual capacity auction that is designed to ensure that, in the long run, the capacity market creates revenues for IPPs that are equal to Net CONE.

At the August 8, 2023 meeting of MISO's Resource Adequacy Subcommittee (RASC), MISO reiterated its intention to file the DSDC proposal with FERC before the end of the third quarter of 2023. At the RASC meeting MISO confirmed that state commissions will continue to have the authority under MISO's tariff to set a Planning Reserve Margin value that differs from MISO's value for utilities under their jurisdiction (for the Commission this would mean the three investor-owned utilities).[10]

The Department recommends that the Commission order Otter Tail to comply with a planning reserve margin based on a loss of load expectations (LOLE) standard of one day of load shed in ten years, calculated considering the power pool to which Otter Tail belongs, which currently is MISO. This recommendation applies to the next IRP filed by Otter Tail and should be re-visited during the next IRP. The primary purpose of this recommendation is to enable the Commission and Otter Tail to observe the results of MISO's experiment with a DSDC, if it is approved by FERC, before implementing it in Minnesota. The Department analyzes this recommendation under the Commission's resource planning decision criteria (Minnesota Rules 7843.0500) below.

The first decision criterion is the ability to maintain or improve the adequacy and reliability of utility service. Both the Department's proposal to maintain the vertical demand curve (at the 1-in-10 LOLE) and the DSDC meet standard reliability criteria. The Department's proposal is merely to maintain the current reliability criteria. The only difference is that MISO's DSDC attempts to maintain reliability by increasing capacity market costs so that additional natural gas fired CTs can be built by IPPs. Minnesota has no need to pay increased costs so as to incentivize IPPs to build new CTs.

The second decision criterion is the ability to keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints. The Department's proposal is specifically targeted at keeping utility rates as low as practicable by maintaining the current reliability standard. First, the goal of the DSDC is to increase overall ratepayer costs so as to create revenues for IPP-owned CTs that currently do not exist. Second, Minnesota's utilities operate under a vertically-integrated, rate-regulated structure. The state of Minnesota in general and Otter Tail's Minnesota ratepayers in particular have no need to pay increased costs to incentivize IPPs to construct new CTs. Minnesota ratepayers do not rely on markets and IPPs for reliability purposes, instead they rely on their utility (here Otter Tail) and the Commission's processes. Therefore, the Department's proposal is tailored to Minnesota's regulatory structure.

The third decision criterion is the ability to minimize adverse socioeconomic effects and adverse effects upon the environment. MISO's proposal is specifically targeted at increasing ratepayer costs in order to incentivize IPPs to build natural gas fired CTs. This will create adverse socioeconomic and

[10] The Department understands that the Wisconsin Public Service Commission has established a one day in ten years LOLE standard in Wisconsin Docket 5-EI-141. Presumably Northern States Power Company d/b/a Xcel Energy's Wisconsin subsidiary would be subject to this requirement.

environmental effects—at least in the areas where the additional CTs would be constructed. In contrast, the Department's proposal will minimize adverse socioeconomic effects and adverse effects upon the environment by reducing MISO's ability to use Minnesota ratepayers to subsize construction of natural gas fired CTs.

The fourth decision criterion is the ability to enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations. The Department does not expect either MISO's proposed DSDC or the current vertical demand curve (which the Department proposes to maintain) to have a significant impact on OTP's ability to respond to changing financial, social, and technological factors. However, to the extent ratepayer funds are scarce, not tying up resources in unneeded capacity costs would maintain the ability to use the existing ratepayer funds to respond to changes in financial, social, and technological factors impacting operations.

The fifth decision criterion is the ability to limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control. As with the fourth criterion, the Department does not expect either MISO's proposed DSDC or the vertical demand curve to have a significant impact on limiting the risk of adverse effects on the utility and its customers. Again, to the extent ratepayer funds are scarce, not tying up resources in unneeded capacity would maintain the ability to use ratepayer funds to construct projects targeted at limiting the risk of adverse effects on OTP and its customers.

The Department recommends that the Commission order Otter Tail to comply with a planning reserve margin based on a LOLE standard of one day of load shed in ten years, calculated considering the power pool to which Otter Tail belongs, which currently is MISO. This recommendation applies only to the next IRP filed by Otter Tail and should be re-visited during the next IRP.

D. MODELING AND EXPANSION PLAN

In the Supplement the Company changed the recommended action regarding Coyote from beginning the process to withdraw from ownership now to beginning the process once major, non-routine capital investment is required. The Supplement summarizes the factors that impacted the Company's decision to change the preferred plan for Coyote as follows:

- Modeling Changes – In OTP's updated modeling there are now additional contingencies that support remaining in Coyote; including high renewable energy cost and low renewable accreditation.
- Capacity Accreditation Questions – MISO is considering several proposals for capacity accreditation and, as of the date of the Supplement, it was unclear which standard MISO would eventually adopt.
- OTP's Capacity Position Relative to Load Growth – Otter Tail's updated modeling includes the addition and projected addition of large loads. OTP expects continued interest from customers, which could affect the Company's overall capacity position.

- Recent Volatility in MISO Energy Markets and Natural Gas Markets – The extreme volatility in these markets that occurred after the Initial Filing demonstrates that forecasting MISO and natural gas commodity markets will always have an inherent amount of uncertainty and risk.
- MISO Capacity Position & Regional Resource Assessment – Since the Petition MISO has shifted from capacity surplus to capacity shortfall and MISO modeling indicates near term capacity risk.

1. *Modeling Background*

The Department used EnCompass to review OTP's modeling efforts. The general process followed by the Department when reviewing capacity expansion model (CEM) data is as follows:

- obtain from the applicant a base case file and the commands necessary to recreate the various scenarios explored by the utility;
- re-run the utility's base case file to make sure the outputs match, and that Department is working with the correct files (matching analysis);
- review the base case inputs and outputs for reasonableness;
- create a new base case, which includes any changes deemed necessary to the utility's base case;
- run scenarios of interest on the new base case to explore various risks and alternative futures;
- assess the results of the scenarios and establish a new preferred plan; and
- run scenarios of interest on the new preferred plan to test the plan's robustness.

The Department's overall goal in reviewing a utility's modeling efforts is to determine if the Company's proposed plan results in a reliable, low cost, low impact system that manages risk, and to recommend modifications if needed. Figure 1 below illustrates how the four overall goals are implemented in EnCompass analysis.

Figure 1: Minnesota Decision Criteria and Modeling

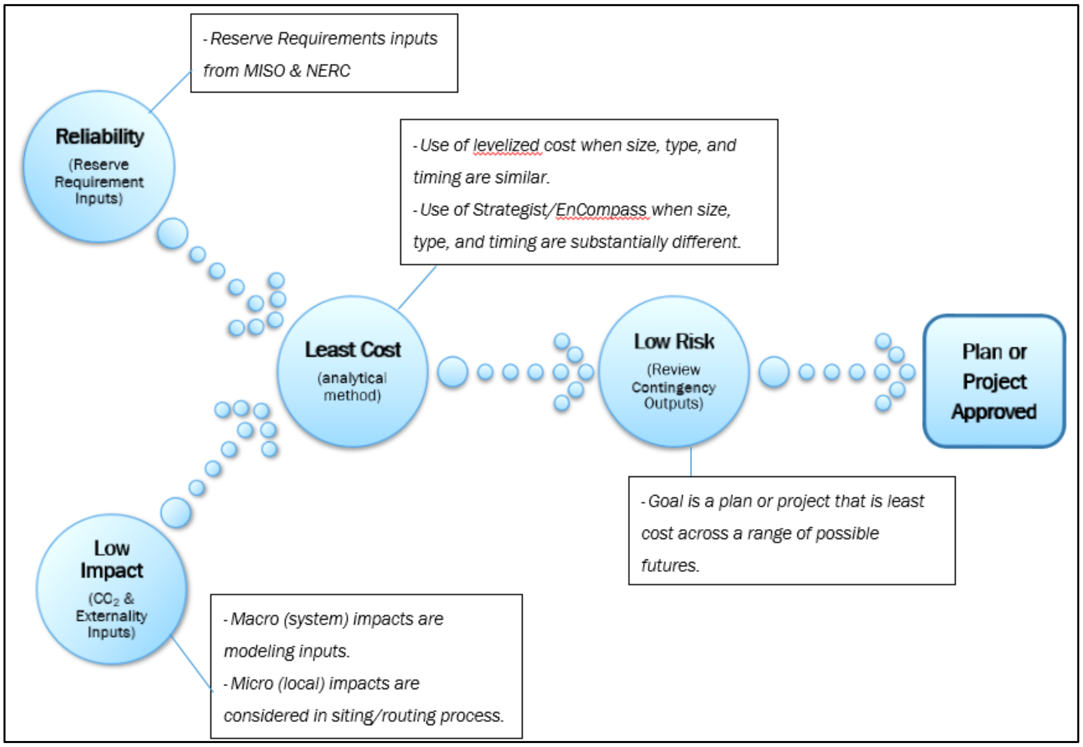

Figure 1 shows that, when evaluating modeling results, the present value of societal costs (PVSC) outputs already include the Commission's reliability and environmental impact criteria. Since EnCompass' function is to minimize cost, that is also included in the modeling results. Thus, when evaluating CEM outputs the Department's focus is on understanding why the model is producing the results, the risks inherent in the results, and how the plan contributes to other goals not directly reflected in the modeling inputs, such as greenhouse gas reduction goals.

2. Matching Analysis

As described in Department comments in several dockets, the point of the Department's matching analysis is to verify that the data received by the Department is the same data used by the utility. Given the complexity of utility databases and the repetitive nature of downloading and saving modeling spreadsheets, it is relatively easy for modelers to have mismatched inputs and outputs.[11] If parties use different data than the utility, all subsequent party analysis has the potential to be meaningless. Therefore, the matching process is a critical component of analyzing the utility's CEM.

[11] For example, a modeler might upload an input spreadsheet into EnCompass (Input 1), run the model and download and save the outputs (Output 1), change the input data within EnCompass without downloading the new input spreadsheet (Input 2), and run the model and download and save the new outputs by overwriting the original outputs (Output 2). In this example, the modeler would have saved the mismatched Input 1 spreadsheets and Output 2 spreadsheets but may believe those datasets correspond to each other.

In most instances it is not necessary to validate every single EnCompass run performed by the utility. Instead, only enough matching needs to be done to ensure that the correct files have been received. While unnecessary, in this case the Department elected to re-run all of OTP's EnCompass runs in order to match each result.

A total of 87 different EnCompass runs were performed by OTP. The Department's re-run arrived at the exact same result as OTP in 31 cases (36%). For the remaining 56 cases (64%) the Department obtained the present value of the cost output, the Actual MIP Basis output, and the MIP Stop Basis input and calculated EnCompass' acceptable range of costs. The Department then was able to verify that OTP's and the Department's cost output values were both within the same acceptable range.[12]

In summary, OTP provided the Department the correct files.

3. EnCompass Inputs and Outputs

The results of the Department's review of the inputs and outputs from OTP's EnCompass model are discussed in this section. The Department was unable to complete its own modeling in the time allowed. Thus, the comments here provide issues for OTP to respond to in reply comments or the next IRP.

i. Environmental and Regulatory Cost Contingencies

The Commission has ordered utilities to provide five specified contingencies that reflect a range of assumptions about environmental and regulatory cost values.[13] Regarding this issue, OTP's response to CEO IR No. 62 referred to Appendix I of the Petition as containing the environmental and regulatory cost contingencies.

The contingencies run for the Petition are no longer relevant. OTP implemented significant changes in load and reliability construct. Therefore, the Department recommends OTP provide the Commission-ordered environmental and regulatory cost contingencies using the updated EnCompass model. In addition, when running the contingencies OTP should ensure that Commission's environmental costs are modeled as external costs within EnCompass and the Commission's regulatory costs are modeled as internal costs.

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[12] The only exception was one run that failed. This run was noted towards the end of the matching process and was not re-run as the underlying files were verified in other runs.
[13] See the Commission's Sep. 30, 2020 *Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs* in Docket No. E999/DI-19-406. Note that the actual text of the order refers to "electricity generation resource acquisition proceedings during 2020 and 2021." However, the Department generally applies the requirement to IRPs as well and uses the same requirement until it is replaced by a new requirement.

ii. Spot Market Inputs

The Department recommends OTP consider several changes to the spot market inputs. The recommended changes are technically straightforward but likely have complex consequences. That means properly implementing the changes may require a series of experiments by OTP to best decide how to improve the spot market construct. The Department recognizes OTP may not be able to be complete the experiments under the current schedule. Therefore, while it would be preferable for the changes to be implemented now, the Department recognizes that implementation may have to wait until the next IRP.

a. Spot Market Capacity Limit

Depending on the specific EnCompass run in question OTP's outputs sometimes show the Company is a significant buyer of short-term capacity in various years.[14] The Company's net capacity imports, which represent short-term capacity purchases, exceed 200 MW in some years. Typically, the larger purchases (50 MW or more) are to cover either the summer or winter peak.[15] The Department assumes that these capacity purchases would be covered through short-term, bilateral purchases and not via MISO's annual planning resource auction.

The Department is concerned that the level of exposure to the short-term capacity market allowed by OTP's inputs is excessive for OTP's system. Therefore, the Department recommends OTP reduce the short-term capacity market purchase limit. Balancing the need to allow some temporary deficits to allow better timing of large-sized additions while avoiding excessive short-term purchases, the Department recommends OTP consider a limit of about 10 % of winter peak or 100 MW for capacity market purchases. It may be necessary for such a reduction to be implemented in steps to allow EnCompass to gradually adapt to the change through expansion unit additions. For example, OTP might use a 250 MW limit through 2025, a 175 MW limit for 2026 and 2027, and a 100 MW limit for 2028 and after.

b. Spot Market Energy Limit

OTP's EnCompass outputs show the Company does not sell into the energy spot market but is a substantial purchaser. As with the capacity market the energy market input design clearly demonstrates that the units added by OTP are needed solely for purposes of serving load and are not being added in order to speculate on spot market prices over the coming decades. The Department considers this to be a reasonable approach for purposes of demonstrating what is driving the need for the new units. However, in order to provide a broader and more realistic view of how OTP's generation units will likely operate within the MISO energy market, the Department recommends OTP re-configure EnCompass so that it has the ability to buy from and sell to the energy spot market.

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[14] OTP does not allow short term capacity sales (a zero MW limit). Presumably the purpose is to demonstrate that additions are clearly needed to serve retail load and are not driven by speculation regarding spot market prices.

[15] Occasionally the fall peak requires capacity purchase and very rarely the spring peak requires capacity purchases. These shoulder season purchases tend to be small—less than 25 MW—most of the time.

There are numerous ways to determine a reasonable limit for energy market transactions. In this case the Department recommends OTP consider the approach used by Northern States Power Company d/b/a Xcel Energy (Xcel).[16] Xcel's approach starts with MISO's *Planning Year 2023-2024 Loss of Load Expectation Study Report* (LOLE Report).[17] MISO now has a seasonal reliability construct and, since OTP is a winter peaking utility, focus on data for the winter season is reasonable. The LOLE Report at Table 5-3 shows that LRZ1 is forecasted to have a winter peak demand of 14,738 MW. OTP's modeling output files show a peak demand of 1,047 MW for winter 2023-2024. Thus, assuming OTP's winter peak is about the same time as LRZ1, OTP represents about 7.1 % of LRZ1 winter peak demand. The LOLE Report at Table ES-3 shows LRZ 1 has a winter Capacity Import Limit (CIL) of 4,937 MW.[18] Multiplying the LRZ1 CIL (4,937 MW) by OTP's share of LRZ peak demand (7.1 %) results in about 350 MW of connection between LRZ1 and MISO that can reasonably be assumed to be usable by OTP.[19] Therefore, the Department recommends OTP consider a spot market energy limit of about 350 MW.

c. Spot Market CO_2 Emissions

OTP's reply to CEO IR No. 65 explains that OTP's EnCompass runs with externalities have a 979.5 lb/MWh CO_2 release rate applied to spot market purchases. The same release rate is used in all years. The Department recommends OTP re-configure the spot market CO_2 release rate so that it uses a time series which decreases each year rather than being the same release rate each year.

The reduction should be designed to reflect the forecasted regional emissions rate.[20] If no other sources are available, a forecasted emissions rate for the MRO-W region is available as a basis to determine the future trajectory of regional emissions.[21] The National Renewable Energy Lab's (NREL) data file indicates that MROW includes all or significant parts of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, and Wisconsin.

d. Spot Market Impact Analysis

One issue that will arise from the Department's recommended changes to the spot market inputs is that expansion units may well be added based merely on speculation regarding a persistent gap between spot market prices and new unit costs over the coming decades. The consequences of this

[16] Details are available in Docket No. E002/RP-19-368.
[17] The LOLE Report is available at: https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf
[18] The LOLE Report shows that LRZ1 has a winter Zonal Import Ability of 4,935 MW, thus the choice of metric (ZIA or CIL) is not material.
[19] If OTP's coincident peak demand (1,014 MW) were used instead of peak demand the result would about 340 MW of usable connection. Thus, choice of demand does not create significant difference.
[20] Note that CO2 emissions rate input apparently is applied by EnCompass to both purchases from and sales to the energy spot market. If OTP redesigns the inputs to allow sales of energy to the spot market, then the future path of OTP's emissions is also a consideration in determining the release rate.
[21] The forecast of future emissions is available on NREL's website at: https://data.nrel.gov/submissions/183

were discussed in the Department's February 11, 2021 in Xcel's most recent IRP (Docket No. E002/RP-19-368) at page 33:

> all Spot Market constructs in CEMs contain an inherent flaw that must be considered when analyzing and interpreting CEM outputs. In economic terms, CEMs contain barriers to entry that prevent utilities, other than the utility being modeled, from responding to any price signals contained in the CEM. For example, it could be the case that new solar units are priced at $8 per MWh while the Spot Market price is set at $10 per MWh in a CEM. In this circumstance, the CEM would add solar to sell into the Spot Market and reduce overall system revenue requirements by the $2 per MWh gap. However, in the real world, responding to the $2 gap between solar prices and Spot Market prices is not limited to the utility being modeled. Other utilities (such as Great River Energy), independent power producers (such as NextEra Energy, Inc.), and others can also respond to the gap. The resulting competition would eliminate the $2 per MWh gap. Thus, the CEM's expected profits may not be realized in the real world. The consequence of this for Xcel's IRP is that units that are added by the CEM may only be added due to the difference in their cost versus the expected Spot Market revenue. That difference might not be realized when entities other than Xcel respond to the price signal.
>
> The same logic applies to existing units, not just new units. For example, assume that that a CEM has a single natural gas price for all units to use and that the CEM's Spot Market prices were designed using that natural gas price and a CT unit (with a heat rate of 10,000 MBTU per MWh) to set the Spot Market price. If the utility being modeled has a CC unit (with a heat rate of 7,000 MBTU per MWh) then that CC unit will be able to take advantage of the heat rate differential (the 3,000 MBTU per MWh gap between the Spot Market's CT and its own heat rate) to sell energy into the Spot Market and reduce overall system revenue requirements by the 3,000 MBTU per MWh gap. Once again, in the real world, responding to the heat rate gap between CC units and Spot Market prices is not limited to the utility being modeled. Other utilities, independent power producers, and others can also respond to the gap. The resulting competition would eliminate the heat rate gap. Again, the CEM's expected profits may disappear in the real world.
>
> In summary, CEM's are a static model of a dynamic process. As a result, it is not enough to simply get a set of results. It is critical to understand why the model is producing the results and to understand the resulting risks from factors outside the model's consideration. The result for the IRP is that units recommended for the Xcel's expansion plan may differ from

> CEM outcomes due to the necessity of considering factors beyond the CEM's ability to consider. In particular, units may be removed from the proposed expansion plan if it appears they are cost effective largely due to an assumed gap between the unit's costs and the expected revenues from the Spot Market.

To address this issue the Department recommends that, as part of OTP's CEM input design process, the Company undertake the following analysis:

- perform a run allowing the CEM to optimize the system;
- lock in the resulting expansion plan, remove one of the expansion units, and re-run the CEM;[22]
- download all the source and sink energy outputs from the two runs;[23] and
- obtain the difference between the sources and sinks energy outputs between the two runs.

The difference might show, for example, that the marginal impact of the additional unit in the first run (which was removed for the second run) is to decrease coal generation, increase sales, increase curtailments, decrease purchases, and so on. Through this analysis the Company can obtain information on what is driving a particular unit to be added. This information can then be used to refine the spot market inputs, expansion unit availability, and so on.

iii. Transmission Upgrade Costs

Table 3-11 of the Petition, shows Coyote early withdrawal scenarios. These scenarios all include costs related to unrecovered book value, decommissioning and salvage value, and lignite supply agreement early termination. Not included are costs related to transmission system upgrades which would be triggered by results of a MISO Attachment Y (unit retirement) study.

Cost estimates could be based on results of a MISO Attachment Y-2 study. However, per the reply to Department IR Nos. 14 and 15 such a study was not requested.[24] OTP stated that the co-ownership group has not signaled the intention to retire Coyote, and therefore a Y-2 study would be premature. The implication of this approach is that the early withdrawal scenarios all include a risk that additional costs will be incurred if OTP's withdrawal triggers the shutdown of Coyote rather than triggering a transfer of the ownership share to another party.

At this time there is no information that would provide an indication of the size of the transmission costs triggered by a retirement of Coyote. The Department recommends OTP discuss in reply comments the potential magnitude of transmission costs associated with Coyote retirement. Note that without such information the risk of a cost increase should be considered qualitatively in any decision regarding Coyote.

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[22] It is simplest if the re-run merely involves a re-dispatch existing system, but this is not necessary.
[23] By sources and sinks the Department refers to generation from various units, spot market energy sales and purchases, curtailed energy, emergency energy, and so on. In other words, everything that might change between the two runs in terms of reported MWh.
[24] This issue was also discussed in OTP's reply to CEO IR No. 61.

iv. Expansion Unit Pricing

The most recent pricing data for new capacity available to the Department was provided in Xcel's May 5, 2023 petition in Docket No. E002/M-22-403. Xcel's petition provided two figures regarding new unit pricing; the figures are reproduced below. The figures show substantial increases in new unit prices in most markets over the past three years. The Department recommends OTP review the data on new unit pricing (or more recent data if it is available to OTP) and re-set the price for new units so that it is more reflective of the current environment.

Figure 1: Edison Energy Q1 Market Report – Trends in Solar PPA Prices[7]

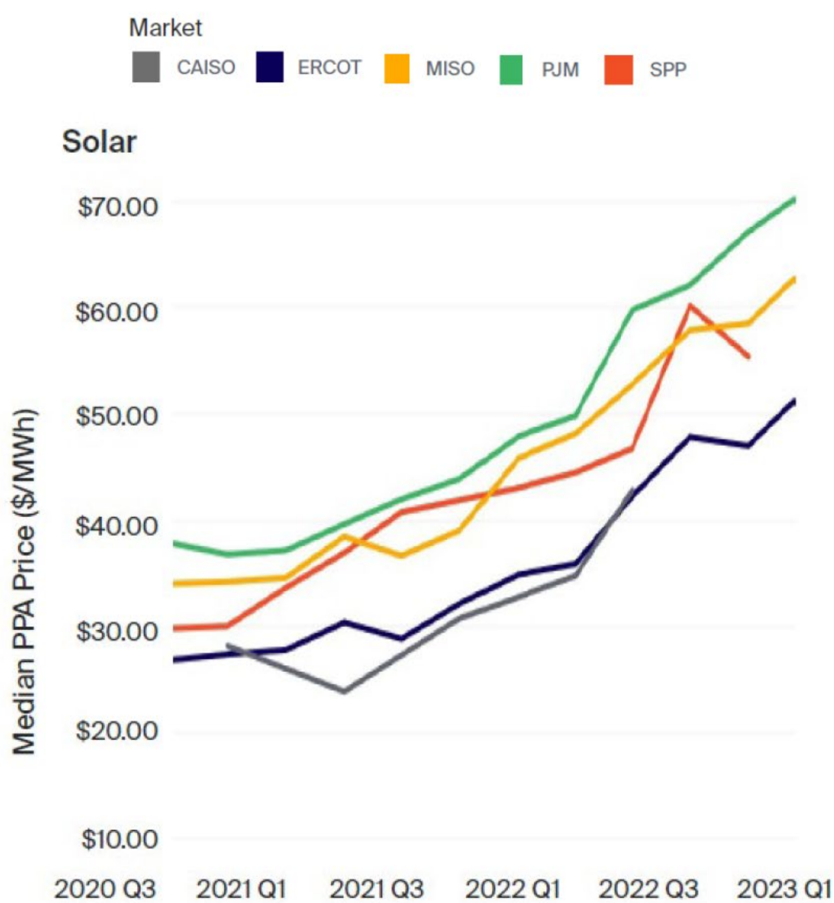
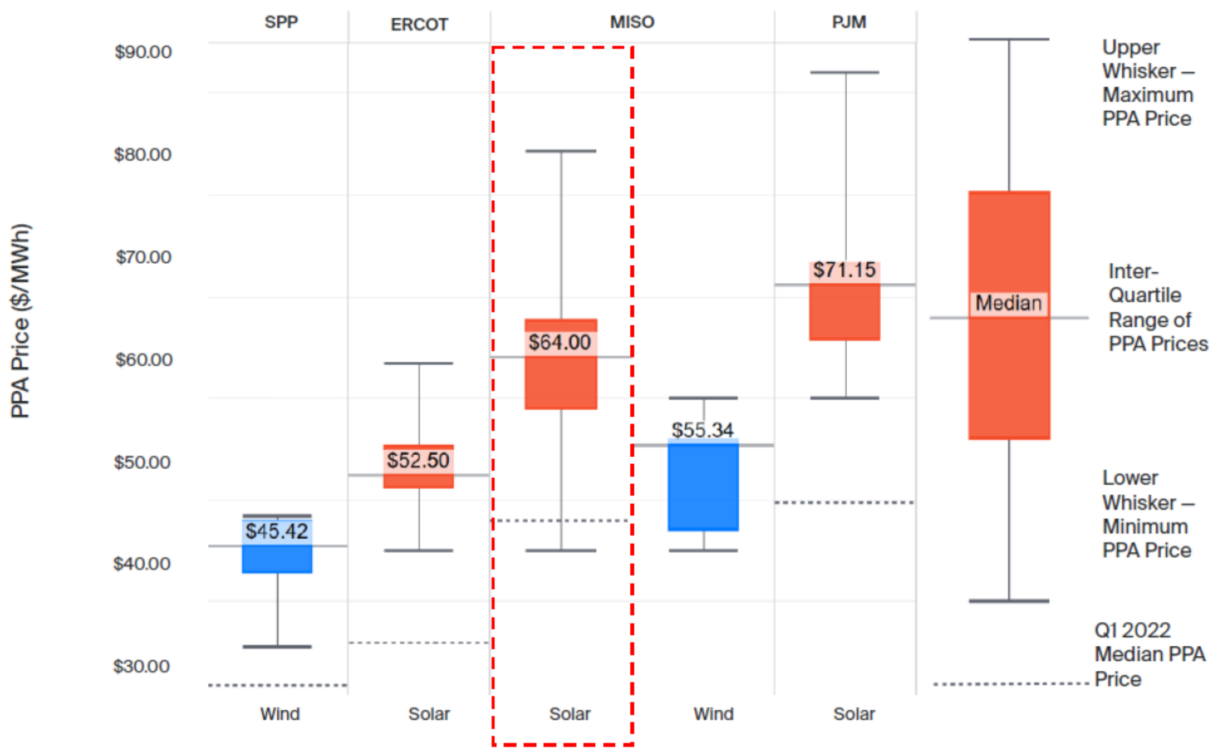


Figure 2: Edison Energy Q1 Market Report – Wind and Solar PPA Prices Q1 2023[9]



PPA prices shown above reflect flat, hub-settled, unit contingent offers inclusive of project RECs received in Q1 2023. Markets and technologies with offers from fewer than four distinct projects are not shown. Some offers shown may no longer be on the market. The dotted line indicates where the median PPA price was one year ago.

v. Early Expansion Units

OTP's reply to CEO IR No. 76 shows that the Company made available at least 400 MW of new capacity as soon as 2025. It may be difficult for OTP to add a large quantity of new capacity that soon. Xcel's most recent request for proposals (RFP) sought at least 900 MW of solar or solar + storage capacity that could achieve commercial operation by December 31, 2025.[25] Xcel received a large number of bids in response to the RFP.[26] In the end Xcel was only able to bring forward half the capacity sought.[27] In addition, the MISO generation interconnection queue (GIQ) has been taking several years to process study groups. Therefore, the Department recommends OTP consider reducing the amount of new

[25] See Docket No. E002/M-22-403 for details of Xcel's RFP.
[26] Xcel received 79 third-party bids and one Xcel self-build bid. In all there were 50 projects proposed by 17 bidders.
[27] Most bids failed due to issues related to inability to provide firm pricing, interconnection, and site control. If OTP can avoid such issues, then having the capacity available in the early years would be less of an issue.

capacity available in the early years of the planning period. Commission approval of a resource plan that relies upon capacity additions that cannot occur would result in reliability issues.

vi. Visibility of Demand Response

OTP's EnCompass inputs contain two specific demand response units, meaning they show up in the model as if they were a supply-side resource. However, the Company's response to CEO IR No. 67 at Attachment 1 shows that demand response, in the form of non-firm load, has been subtracted within the equations creating the inputs on the demand-side of the model. Having demand response show up in two different places:

- creates the potential for mis-counting the amount of demand response available;
- creates confusion on the part of parties reviewing the model; and
- masks the true level of demand response resources available to the Company.

The Department recommends that OTP consider locating all demand response resources in one section of the CEM or explain why locating demand response in multiple locations is reasonable.

vii. Solar Degradation

Data available on solar panel performance typically indicates a slow degradation over time. NREL reports that degradation is typically less than 1 percent annually.[28] For example, a 100 MW solar unit installed in 2025 that degrades by 0.5 percent annually would have a capacity of about 90 MW in 2045. While the annual degradation amount is small, the lost capacity could be an important factor in the ultimate decision regarding what types of capacity to add and in maintaining a reliable system. Therefore, due to the long timeframe considered in an IRP the Department recommends OTP include a small degradation factor for solar capacity.[29, 30]

viii. Summary of Modeling Recommendations

The Department recommends OTP respond to the following modeling issues, either in reply comments or the next IRP OTP:

1. provide the Commission-ordered environmental and regulatory cost contingencies using the updated EnCompass model;
    a. when running the contingencies OTP should ensure that the Commission's environmental costs are modeled as external costs and the Commission's regulatory costs are modeled as internal costs;

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[28] For more information see https://www.nrel.gov/pv/lifetime.html
[29] For this IRP OTP ran EnCompass for the years 2023 to 2050.
[30] For an example see Xcel's June 25, 2021 reply comments at Appendix A, page 17 of 35 in Xcel's 2019 IRP (Docket No. E002/RP-19-368).

2. reduce the short-term capacity market purchase limit to about 100 MW, potentially in a series of steps;
3. re-configure the energy market so that OTP has the ability to buy from and sell to the energy spot market about 350 MW;
4. re-configure the spot market CO2 release rate so that it uses a time series which decreases each year;
5. study the impact of spot market changes using the following process:
    a. perform a run allowing the CEM to optimize the system;
    b. lock in the resulting expansion plan, remove one of the expansion units, and re-run the CEM;
    c. download all the source and sink energy outputs from the two runs; and
    d. obtain the difference between the sources and sinks energy outputs between the two runs;
6. discuss in reply comments the potential magnitude of transmission costs associated with Coyote retirement;
7. review data on new unit pricing and re-set the price for new units;
8. consider reducing the amount of new capacity available in the early years of the planning period;
9. consider locating all demand response resources in one section of the CEM or explain why locating demand response in multiple locations is reasonable; and
10. include a small degradation factor for solar capacity.

E. MINNESOTA CARBON FREE STANDARD

Minnesota Statutes § 216B.1691, subd. 2 (g)[31] states:

> In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:
> (1) 2030 80 percent for public utilities;
> 60 percent for other electric utilities
> (2) 2035 90 percent for all electric utilities
> (3) 2040 100 percent for all electric utilities.

[31] The language taken from:
https://www.revisor.mn.gov/bills/text.php?number=HF7&type=bill&version=2&session=ls93&session_year=2023&session_number=0

Minnesota Statutes § 216B.1691, subd. 4 (b)[32] states:

> (b) In lieu of generating or procuring energy directly to satisfy a standard obligation under subdivision 2a, 2f, or 2g, an electric utility may utilize renewable energy credits allowed under the program to satisfy the standard.

The Supplement states that owned and contracted renewable generation will allow the Company to comply with this legislation. Tables 4-5 and 4-6 of the Supplement provide a summary of how OTP will satisfy the Clean Energy Law's standards in the prescribed timeframe. Table 4-5 assumes for analysis that OTP withdraws from Coyote Station by 2030. Table 4-6 assumes for analysis that OTP retains Coyote Station for the balance of its remaining life (2040).

As indicated in the Department's August 8, 2023 comments regarding Great River Energy's IRP (Docket No. ET2/RP-22-75), the Commission has opened a generic docket and has indicated it will be exploring how utilities will comply with the Carbon-free standard.[33] The Commission's generic docket will provide additional clarity on compliance and OTP's current information should not be taken as evidence of its ability to comply or not comply with the new standard. The Department will defer further comment on the carbon-free energy standard until the Commission's investigation provides more detailed guidance.

F. 50 PERCENT AND 75 PERCENT RENEWABLES AND CONSERVATION

Minnesota Statutes § 216B.2422, subd. 2 (c) requires that "As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources."

Supplemental Table 3-1 of the Supplement shows that OTP's proposed plan adds new renewable resources, dual fuel capability at Astoria, and energy storage; in addition, OTP plans to maintain existing conservation programs. The addition of dual fuel capability at Astoria will result in very small increases in generation at Astoria. These increases would be offset by generation decreases elsewhere. The addition of storage will result in a transfer of energy output from one time to another, with some impact from losses in the battery's charge/discharge process. Overall, the impact of adding dual fuel capability at Astoria and energy storage will be negligible. Therefore, the Department concludes that OTP's proposed plan exceeds the requirements of Minnesota Statutes § 216B.2422 and no further analysis of the requirement is necessary.

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[32] The language taken from: https://www.revisor.mn.gov/bills/text.php?number=HF7&type=bill&version=2&session=ls93&session_year=2023&session_number=0
[33] See Docket No. E999/CI-23-151.

G. RENEWABLE ENERGY STANDARD

1. Background

Minnesota Statutes § 216B.1691, subd. 2 (a)[34] establishes the renewable energy standard (RES) which requires that OTP:

> shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from an eligible energy technology that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:
> 1) 2012 12 percent
> 2) 2016 17 percent
> 3) 2020 20 percent
> 4) 2025 25 percent
> 5) 2035 55 percent.

An eligible energy technology is defined by Minnesota Statutes § 216B.1691, subd. 1[35] as an energy technology that:

> generates electricity from the following renewable energy sources:
> 1) solar;
> 2) wind;
> 3) hydroelectric with a capacity of:
>   i. less than 100 megawatts; or
>   ii. 100 megawatts or more, provided that the facility is in operation as of the effective date of this act;
> 4) hydrogen generated from the resources listed in this paragraph; or
> 5) biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of

[34] Updated language taken from: https://www.revisor.mn.gov/bills/text.php?number=HF7&type=bill&version=2&session=ls93&session_year=2023&session_number=0

[35] Updated language taken from: https://www.revisor.mn.gov/bills/text.php?number=HF7&type=bill&version=2&session=ls93&session_year=2023&session_number=0

> wastewater sludge to produce electricity; and, except as provided in subdivision 1a, an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minnesota Statutes § 216B.1691 subd. 2f requires that, in addition to the RES obligation, a publicly owned utility generate or procure solar energy equal to at least 1.5 percent of its Minnesota retail sales by the end of 2020. For OTP, at least ten percent of the 1.5 percent goal must be generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less. The solar energy standard (SES) statute (Minn. Stat. § 216B.1691, subd. 2(f)) excludes certain retail sales to iron mining, paper, and wood products manufacturers from the calculation of the SES requirement.

2. Renewable Energy Standard Compliance

The Department reviews historical compliance with the RES statute in a biennial report to the legislature; *Minnesota Renewable Energy Standard: Utility Compliance* (RES Report), filed January 12, 2023.[36] The RES Report concluded that "All of the utilities subject to the Minnesota Renewable Energy Standard have demonstrated compliance with the 2021 Renewable Energy Standard requirements."

Regarding future compliance the Department notes that Table 3 of the RES Report estimates OTP can comply with the RES through 2035. In addition, OTP plans substantial new additions of RES qualifying resources in the 5-year action plan.

As indicated above, the Commission has opened a generic docket and has indicated it will be exploring how utilities will comply with the renewable energy standard.[37] The Commission's generic docket will provide additional clarity on compliance and OTP's current information should not be taken as evidence of its ability to comply or not comply with the new standard. The Department will defer further comment on the renewable energy standard until the Commission's investigation provides more detailed guidance.

3. Solar Energy Standard Compliance

The Department reviews compliance with the SES statute in the RES Report as well. The RES Report concluded that OTP "complied with the 2021 RES requirement and the 2021 non-small SES requirements." However, regarding the small-scale SES requirement, the RES Report stated "Otter Tail partially complied with 2021 small-scale SES requirements through the purchase and retirement of solar renewable energy credits." Thus, OTP had difficulty in obtaining sufficient small-scale solar resources.

Regarding future compliance Table 3-1 of the Supplement shows that OTP's preferred plan includes 100 MW of solar resources in 2027, 2028, 2030, and 2032. Assuming a 100 MW solar facility has a 24

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[36] The report is available at: https://www.lrl.mn.gov/docs/2023/mandated/230009.pdf
[37] See Docket No. E999/CI-23-151.

percent capacity factor and 50 percent of the energy is allocated to Minnesota, it would produce around 105 GWh annually for Minnesota retail customers.[38] Adding another 100 GWh[39] annually from the Hoot Lake Solar project, OTP's total solar energy would be around 205 GWh annually in 2027 and increasing in subsequent years. Per the Company's response to Department IR No. 10 OTP's forecasted retail sales in Minnesota are between 2,260 and 2,276 GWh annually. Thus, the generic solar projects in the expansion plan combined with the Hoot Lake Solar project are more than enough to meet the ten percent by 2030 solar goal.

As indicated in the Department's discussion above, the Commission has opened a generic docket and has indicated it will be exploring how utilities will comply with the solar energy standard.[40] The Commission's generic docket will provide additional clarity on compliance and OTP's current information should not be taken as evidence of its ability to comply or not comply with the new standard. The Department will defer further comment on the solar energy standard until the Commission's investigation provides more detailed guidance.

H. MINNESOTA GREENHOUSE GAS EMISSIONS REDUCTION GOAL

Minnesota Statutes § 216H.02, subd. 1[41] now states, in part:

> (a) It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing greenhouse gas emissions by at least the following amounts, compared with the level of emissions in 2005:
>
> (1) 15 percent by 2015;
>
> (2) 30 percent by 2025;
>
> (3) 50 percent by 2030; and
>
> (4) to net zero by 2050.
>
> …
>
> (c) The targets under paragraph (a) must be reviewed annually by the commissioner of the Pollution Control Agency, taking into account the latest scientific research on the impacts of climate change and strategies to reduce greenhouse gas emissions published by the Intergovernmental Panel on Climate Change. The commissioner must forward any recommended changes to the targets to the chairs and ranking minority members of legislative committees with primary jurisdiction over climate change and environmental policy.

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[38] Calculated as 100 MW * 8,760 hours * 24 percent capacity factor * 50 percent allocation.
[39] Calculated as 49 MW * 8,760 hours * 24 percent capacity factor * 100 percent allocation.
[40] See Docket No. E999/CI-23-151.
[41] Updated language taken from: https://www.revisor.mn.gov/laws/2023/0/60/laws.12.61.0

Since review of compliance has been clearly assigned to the Pollution Control Agency (PCA) the Department has no comment on OTP's compliance with Minnesota's greenhouse gas emissions reduction goal. Presumably the PCA will be able to provide guidance on how the statute is to be interpreted and provide analysis of OTP's compliance under PCA's interpretation.

4. Renewable Integration

Regarding integrating renewables the Order required the Petition include "A discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service." In response to this requirement OTP stated:

> Otter Tail relied on the MISO developed Renewable Integration Impact Assessment (RIIA) study to help identify inflection points associated with increasing levels of renewable generation. The RIIA study identified five risks to address as more renewables are integrated into the generation portfolio: (1) stability risk, (2) shifting periods of grid stress, (3) shifting periods of energy shortage risk, (4) shifting flexibility risk, and (5) insufficient transmission. Otter Tail sees these risks in its own resource planning and in particular views the transmission queue for new interconnection of wind as a significant hurdle to introducing new wind resources outside of utilizing surplus interconnection at existing plants. In addition to the MISO transmission queue, the EnCompass modeling does lean towards selecting solar resources. *Citation omitted.*

The Department agrees with OTP that MISO's GIQ can be a significant hurdle to introducing large quantities of new resources. OTP's supplemental preferred plan includes the following additions:

- 100 MW of solar in 2027 and again in 2028;
- 200 MW of wind in 2029;
- 100 MW of solar in 2030;
- 150 MW of wind in 2031;
- 100 MW of solar and 25 MW of energy storage in 2032.

Thus, the quantity of resources being added in OTP's preferred plan are significant and may not be available through the standard MISO GIQ process. OTP's supplemental preferred plan indicates the Company expects to use surplus interconnection for the solar capacity to avoid some GIQ issues. However, the 350 MW of wind are not labeled as using surplus interconnection. Since the wind additions are scheduled to be acquired around the time MISO's long range transmission planning tranche 1 projects are scheduled to be in-service the GIQ may be less of an issue. However, the remaining factors, stability risk, shifting periods of grid stress, shifting periods of energy shortage risk, and shifting flexibility risk remain.

I. ENERGY EFFICIENCY

In Docket No. E017/RP-16-386 the Commission established an average annual energy savings goal of 46.8 GWh (1.6 percent of retail sales) for resource-planning purposes. In the Petition at Table 2-1 OTP noted that the Company achieved average annual energy savings of 1.86 percent of retail sales. The Supplement states that "This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in Minnesota's Energy Conservation and Optimization Act of 2021."

As discussed above the Department did not complete EnCompass modeling for this IRP. Thus, the Department cannot determine if the Company's proposed level of savings is the most cost-effective amount from a resource planning perspective.

The Company stated that its preferred plan complies with Minnesota's Energy Conservation and Optimization Act. OTP's compliance will be reviewed in the Company's filings with the Department to implement energy efficiency programs. Therefore, no analysis of OTP's proposed level of energy savings was conducted for this proceeding.

J. COMPETITIVE BIDDING

Minnesota Statutes § 216B.2422, subd. 5[42] states that:

> (a) A utility may select resources to meet its projected energy demand through a bidding process approved or established by the commission. A utility shall use the environmental cost estimates determined under subdivision 3 and consider local job impacts when evaluating bids submitted in a process established under this subdivision.
>
> (b) Notwithstanding any other provision of this section, if an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the commission, a certificate of need proceeding under section 216B.243 is not required.

The Commission's May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing* in Docket No. E002/RP-04-1752 stated the overall purpose of a bidding process:

> The purpose of the competitive process—getting the best overall price for ratepayers—cannot be achieved without robust competition. And robust

[42] Updated language taken from https://www.revisor.mn.gov/laws/2023/0/7/laws.0.21.0#laws.0.21.0

> competition cannot be achieved without two things: (1) a fair, predictable, and transparent competitive process; and (2) widespread agreement that the process is fair, predictable, and transparent.
>
> Potential suppliers will not commit the resources necessary to compete effectively, and will not disclose the sensitive information often required to evaluate their competitive proposals, unless they have confidence in the objectivity, good faith, and predictability of the competitive process. In fact, to attract competitive proposals, it may matter less what the rules are—assuming fundamental rationality and basic fairness—than whether all potential players know the rules and know that they will be enforced evenhandedly.

To evaluate a potential bidding process for OTP, the Department started with Xcel's bidding process as discussed in the Department's February 11, 2021 comments in Docket No. E002/RP-19-368.

First, a bidding process must address the time lag between a resource plan order and the start of the bidding process. This time lag creates the potential for changed circumstances between the time the Commission issues an IRP order and OTP issues an RFP. The Department started with the Commission's December 13, 2013 *Order Approving Acquisitions with Conditions* in Docket Nos. E002/M-13-603 and E002/M-13-716 which addressed this potential:

> … while a resource plan is intended to plot a utility's course for the next 15 years, it is based on facts known as of a specific point in time. As more facts become known, circumstances change and utilities must adapt – even in the absence of a new resource plan order.

Therefore, the Department recommends the Commission enable OTP to issue an RFP that differs from the most recent Commission IRP order if changed circumstances warrant. This means that the size, type, and timing of resources requested in an RFP may differ from the size, type, and timing in the most recent Commission IRP order if warranted.

Second, the Department also notes that power purchase agreements (PPA) can include a right of first offer (ROFO) clause. The Department does not object to the inclusion of a ROFO in PPAs. However, when negotiations occur regarding a ROFO both parties, OTP and the seller, have an incentive to increase the price as much as possible. In recognition of this fact, basic accounting principles indicate that an asset which was already placed in service and continues to operate under a PPA should have the purchase reflected at net book value and that acquisition adjustments should not be reflected in the purchase price. The Department's March 5, 2019 comments in Docket No. IP6949, E002/PA-18-702 clarified this by stating:

> The Department notes that traditionally, utility assets are recorded and recovered using the original cost of the asset and the related accumulated

> depreciation or resulting net book value of the asset. Acquisition adjustments are on top of the net book value and as a result require a significant finding of benefits to offset or justify this higher acquisition adjustment or premium before rate recovery is allowed, especially for utility assets that were already being used for public service (like MEC [Mankato Energy Center]). Use of net book value in rate base is consistent with Federal Energy Regulatory Commission requirements and Minnesota requirements under 216B.16, subd. 6…

Therefore, in order to allow a ROFO provision to be included in PPAs while simultaneously protecting ratepayers in a situation where both sides of the negotiations have an incentive to maximize costs, the Department recommends that the Commission cap any ROFO offer made by OTP at net book value.

Third, in addition to the ROFO provision, the Department notes that when issuing the RFP OTP would have wide latitude regarding what to include and exclude in the RFP process. The Department notes that, when the bidding process is used, the Company should be required to seek proposals for both PPA and build–transfer (BT) projects. Thus, the Department recommends that the Commission require any RFP issued by OTP to include the option for both PPA and BT proposals unless the Company can demonstrate why either a PPA or BT proposal is not feasible.

Finally, the Department notes that over time utilities use various technologies as a proxy for a peaking resource. The Department is neutral as to the actual technology that would be acquired to fill any future needs for peaking resources. Thus, the Department recommends that the Commission require that any RFP documents for peaking resources issued by OTP be technology neutral.

The Department recommends the Commission approve a bidding process for OTP's future resource acquisitions as follows:

1. OTP should use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. ensure that the RFP includes the option for both PPA and BT proposals unless the Company can demonstrate why either a PPA or BT proposal is not feasible;
4. provide the Department and other stakeholders with notice of RFP issuances;
5. notify the Department and other stakeholders of material deviations from initial timelines;
6. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
7. where OTP or an affiliate proposes a project:
    a. require OTP to create separate teams for the Company's project and for evaluation of the bids received;
    b. engage an independent auditor to oversee the bid process and provide a report for the Commission;

8. include in the RFP a plan to address the impact of material delays or changes of circumstances on the bid process;
9. cap any ROFO offer made by OTP at net book value; and
10. ensure that any RFP documents for peaking resources issued are technology neutral.

III. DEPARTMENT RECOMMENDATIONS

A. RECOMMENDATIONS FOR COMMISSION ACTION

The Department recommends that the Commission order Otter Tail to comply with a planning reserve margin based on a LOLE standard of one day of load shed in ten years, calculated considering the power pool to which Otter Tail belongs, which currently is MISO. This recommendation applies only to the next IRP filed by Otter Tail and should be re-visited during the next IRP.

The Department recommends the Commission approve a bidding process for OTP's future resource acquisitions as follows:

1. OTP should use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. ensure that the RFP includes the option for both PPA and BT proposals unless the Company can demonstrate why either a PPA or BT proposal is not feasible;
4. provide the Department and other stakeholders with notice of RFP issuances;
5. notify the Department and other stakeholders of material deviations from initial timelines;
6. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
7. where OTP or an affiliate proposes a project:
    a. require OTP to create separate teams for the Company's project and for evaluation of the bids received;
    b. engage an independent auditor to oversee the bid process and provide a report for the Commission;
8. include in the RFP a plan to address the impact of material delays or changes of circumstances on the bid process;
9. cap any ROFO offer made by OTP at net book value; and
10. ensure that any RFP documents for peaking resources issued are technology neutral.

B. RECOMMENDATIONS FOR OTTER TAIL

The Department recommends OTP respond to the following modeling issues, either in reply comments or the next IRP:

1. provide the Commission-ordered environmental and regulatory cost contingencies using the updated EnCompass model;
    a. when running the contingencies OTP should ensure that the Commission's environmental costs are modeled as external costs and the Commission's regulatory costs are modeled as internal costs;
2. reduce the short-term capacity market purchase limit to about 100 MW, potentially in a series of steps;
3. re-configure the energy market so that OTP has the ability to buy from and sell to the energy spot market about 350 MW;
4. re-configure the spot market CO2 release rate so that it uses a time series which decreases each year;
5. OTP study the impact of spot market changes using the following process:
    a. perform a run allowing the CEM to optimize the system;
    b. lock in the resulting expansion plan, remove one of the expansion units, and re-run the CEM;
    c. download all the source and sink energy outputs from the two runs; and
    d. obtain the difference between the sources and sinks energy outputs between the two runs;
6. discuss in reply comments the potential magnitude of transmission costs associated with Coyote retirement;
7. review data on new unit pricing and re-set the price for new units;
8. consider reducing the amount of new capacity available in the early years of the planning period;
9. consider locating all demand response resources in one section of the CEM or explain why locating demand response in multiple locations is reasonable; and
10. include a small degradation factor for solar capacity.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E017/RP-21-339

Dated this **13th** day of **September 2023**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Laura	Bishop	Laura.Bishop@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_21-339_21-339
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_21-339_21-339
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-339_21-339
Brooke	Cunningham	Health.Review@state.mn.us	Minnesota Department of Health	PO Box 64975 St. Paul, MN 55164-0975	Electronic Service	No	OFF_SL_21-339_21-339
Aaron	Decker	adecker@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_21-339_21-339
Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters	700 Olive Street St. Paul, MN 55130	Electronic Service	No	OFF_SL_21-339_21-339
Kristin W	Duncanson	kristin@duncansongrowers.com		57746 Highway 30 Mapleton, MN 56065	Electronic Service	No	OFF_SL_21-339_21-339
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_21-339_21-339
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-339_21-339
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_21-339_21-339
Barb	Freese	bfreese@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-339_21-339
Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company	PO Box 496 Fergus Falls, MN 56538-0496	Electronic Service	Yes	OFF_SL_21-339_21-339
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-339_21-339
Julie	Goehring	julie@redriverbasincommission.org		708 70 Ave NW Moorhead, MN 56560	Electronic Service	No	OFF_SL_21-339_21-339
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-339_21-339
Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club	2101 Webster St Ste 1300 Oakland, CA 94612	Electronic Service	No	OFF_SL_21-339_21-339
Nathan	Jensen	njensen@otpco.com	Otter Tail Power Company	215 S. Cascade St. Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.	11 East Superior St Ste 125 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-339_21-339
William D	Kenworthy	will@votesolar.org	Vote Solar	332 S Michigan Ave FL 9 Chicago, IL 60604	Electronic Service	No	OFF_SL_21-339_21-339
Kate	Knuth	kate.knuth@gmail.com		2347 14th Terrace NW New Brighton, MN 55112	Electronic Service	No	OFF_SL_21-339_21-339
Randy	Kramer	rlkramer89@gmail.com	Water and Soil Resources Board	42808 Co. Rd. 11 Bird Island, MN 55310	Electronic Service	No	OFF_SL_21-339_21-339
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339
Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-339_21-339
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-339_21-339
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-339_21-339
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Debra	Opatz	dopatz@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-339_21-339
Stephan	Roos	stephan.roos@state.mn.us	MN Department of Agriculture	625 Robert St N Saint Paul, MN 55155-2538	Electronic Service	No	OFF_SL_21-339_21-339
Nathaniel	Runke	nrunke@local49.org	International Union of Operating Engineers Local 49	611 28th St. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_21-339_21-339
John	Saxhaug	john_saxhaug@yahoo.com		3940 Harriet Ave Minneapolis, MN 55409	Electronic Service	No	OFF_SL_21-339_21-339
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-339_21-339
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-339_21-339
Cary	Stephenson	cStephenson@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	Yes	OFF_SL_21-339_21-339
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	Yes	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 St. Paul, MN 55104	Electronic Service	Yes	OFF_SL_21-339_21-339
Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club	Environmental Law Program 1536 Wynkoop St Ste 200 Denver, CO 80202	Electronic Service	No	OFF_SL_21-339_21-339
Cameron	Winton	winton.cam@dorsey.com	Dorsey & Whitney LLP	50 S 6TH ST STE 1500 Minneapolis, MN 55402	Paper Service	No	OFF_SL_21-339_21-339
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339